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Vice President
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May 11, 1998

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American Petroleum Institute Comments on Minerals Management Service Proposal on Valuation of Crude Oil Produced on Indian Leases 30 CFR 206, 63 FR 7089 (February 12, 1998)

Dear Mr. Guzy:

The American Petroleum Institute ("API") is a national trade association representing about 400 member companies. Our members are engaged in all aspects of the petroleum industry: exploration, production, transportation, refining and marketing. Many of our members are actively engaged in activities involving crude oil produced on Indian lands and together they account for the vast majority of crude oil royalties paid every year. We therefore have a substantial interest in the Minerals Management Service's ("MMS") Indian lands crude oil valuation rulemaking.

In many respects, the MMS' February 12, 1998, Indian lands crude oil valuation proposal ("Indian Oil Proposal") parallels the MMS' February 6, 1998, Federal lands crude oil valuation proposal ("Federal Oil Proposal"). In the interests of brevity, these comments incorporate by reference the April 3, 1998, comments on the Federal Oil Proposal and focus on important differences between the two proposals. For the record in this rulemaking, attached is a full set of the API April 3, 1998, comments ("API April 1998 Comments"). [1]

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[1] *See, also,* API May 27, 1997 comments on the MMS' initial proposal at 62 FR 3742 (January 24, 1997); API August 1, 1997 comments on the MMS' supplementary proposal at 62 FR 16116 (April 4, 1997); API November 4, 1997 comments on the alternatives for rulemaking and related workshops at 62 FR 49460

1. Reliance on NYMEX Prices

First, the preamble to the Indian Oil Proposal states that: "MMS is proposing NYMEX prices primarily because they are perceived to best reflect current domestic crude oil market value on any given day and the minimal likelihood that any party could influence them." Indian Oil Proposal at 63 FR 7089, 7092. For reasons set forth at length in API's April 1998 and earlier rulemaking comments on the Federal Oil Proposal, API disagrees that NYMEX prices are an appropriate measure of the value of production at the lease. Indeed, except for the special case of the Rocky Mountain Region, the MMS in its Federal Oil Proposal has abandoned NYMEX prices as the measure of value. *See* API April 1998 Comments at 2-4. Moreover, in the preamble to the Indian Oil Proposal, the MMS acknowledges that "the location/quality adjustments needed to derive lease value using NYMEX would involve considerable administrative effort for all involved." 63 FR 7093.

Second, proposed §206.52 would require that royalties be paid on the highest of (a) the average of the five highest daily NYMEX future settle prices for the prompt month, (b) the gross proceeds received from the sale of oil under an arm's length contract, or (c) the major portion value calculated by MMS. While API certainly opposes use of NYMEX (or any index) in combination with the simplistic differentials proposed, using only the five highest NYMEX prices in a month to calculate the value of oil produced every day of the month is hardly justified by the MMS' "administrative simplicity" rationale at 63 FR 7092.

Third, in response to the MMS request for suggestions on market value indicators other than NYMEX, API's April 1998 comments on the Federal Oil Proposal address the use of tendering and royalty-in-kind. *See* API April 1998 Comments at 2-5. These alternatives, as well as the modified benchmarks described by API and other industry commenters in the Federal oil valuation rulemaking should be considered in this rulemaking as well.

2. Definition of "Lessee"

Proposed §206.51 would define "lessee" expansively to mean:

> . . . any person to whom an Indian Tribe or allottee issues a lease, and any persons assigned an obligation to make royalty or other payments required by the lease. This includes any person holding a lease interest (including operating rights owners) as well as an operator, purchaser, or other person who makes royalty payments to MMS or the lessor on the lessee's behalf. Lessee includes all affiliates, including but not limited to a company's production, marketing, and refining arms.

(September 22, 1997); and, Joint Association December 5, 1997 comments on the rulemaking issues in general.

As unduly expansive as the §206.51 definition of "lessee" is, many of the succeeding operative provisions use the vaguer term "you" which blurs the lessee's obligations under these proposed regulations. For example, under §206.52(b), if a non-affiliated purchaser remits royalties on the production which it purchases, is it required to pay royalties on the "sale of your oil under an arm's length contract"? In other words, does the purchaser pay royalties on the price it receives for the resale of the oil or the price it pays to the producer? Likewise, does §206.52(b) require that a producer pay royalty on the basis of prices received by its refinery for the sale of refined oil products?

3. Major Portion Analysis

First, proposed §206.52(c)(3) would replace the well-established 50% plus 1 rule with a 75th percentile rule because of Indian representative assertions that the existing rule uses a *median* which is not synonymous with *major*. However, the top 25% is plainly not "major portion" in the common use of the term nor as the Interior Board of Land Appeals has employed the term. *See Ladd Petroleum Corp.*, 127 IBLA 163,173 (1993)(more than 50% is major). The term "major portion" is an integral part of Indian lease agreements and the MMS cannot unilaterally redefine a term central to the original bargain.

Second, proposed §206.52(c)(2) suggests that the MMS is reserving the right to consider prices on the entire Indian reservation or, potentially, in a "designated area" which is larger than the Indian reservation and larger than the field. However, existing lease provisions require payment of "the highest price paid or offered at the time of production for the major portion of oil production from the same field."

Third, it appears that, in calculating the major portion analysis, the MMS would not look just to prices actually received but also to the adjusted NYMEX prices reported by lessees. However, the purpose of the major portion analysis is to assure that the Indian lessor receives a royalty based on a price comparable to (most) other prices actually received in the field or area, not to guarantee that the royalty will be based on a hypothetical price unlinked to actual sales.

4. Duty to Market Free of Charge

Proposed §206.53(d) includes the requirement that lessees market oil at no cost to the Indian lessor. API's comments on the Federal oil valuation rulemaking address this squarely, showing that such a requirement is unlawful. *See* API April 1998 Comments at 5. Moreover, this duty to market free of charge is already the subject of

litigation instituted on the MMS gas transportation allowance rule, 62 FR 65753 (December 16,1997). *See Independent Petroleum Association of America v. Armstrong et al., 98 CV 531 (filed March 2, 1998) and American Petroleum Institute v. Babbitt et al.,98 CV 631 (filed March 13, 1998).*

5. Transportation Costs

First, §206.60 would disallow transportation allowances for transportation within the boundaries of an Indian reservation because Indian lessors assert that leases are typically silent on transportation costs. Yet in the preamble the MMS states that Indian lessors "acknowledge that costs to move production away from the reservation. . . may be legitimate deductions." 63 FR 7094(middle column). The MMS has long permitted the deduction of transportation allowances, and there is no basis for disallowing some transportation costs while permitting the deduction of others. *See, e.g.*, 53 FR 1207 (January 15, 1998) explaining the MMS long-standing policy of granting transportation allowances and citing *Kerr-McGee Corp.*, 22 IBLA 124 (1975). With respect to the movement of production, only true gathering costs are non-deductible.

Second, for myriad reasons, the MMS should not categorically disallow transportation allowances based on FERC tariffs. *See* API April 1998 comments at 7-9.

6. Reporting

Proposed §206.53 would require lessees and their purchasers to provide sales data for production sold, purchased or obtained from an Indian reservation and from "nearby fields and areas." Since the MMS offers no authority for requiring submission of data respecting fee and state leases, API urges the MMS to clarify and narrow this provision to exclude data for fee and state leases.

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If you have questions, please call David Deal of my staff at (202) 682 - 8261.

Sincerely,

G. William Frick
Vice President, General
Counsel and Secretary

Enclosure

Before the United States
Department of the Interior
Minerals Management Service

American Petroleum Institute and Western States Petroleum Association Comments on Minerals Management Service Supplementary Proposal for Valuation of Crude Oil Produced on Federal Leases

63 FR 6113 (February 6, 1998)
30 CFR Part 206

Volume I - Comments

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April 3, 1998

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April 3, 1998

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American Petroleum Institute and
Western States Petroleum Association
Comments on Minerals Management Service
Supplementary Proposal on
Valuation of Crude Oil Produced on Federal Leases
30 CFR 206, 63 FR 6113 (February 6, 1998)

Dear Mr. Guzy:

The American Petroleum Institute ("API") is a national trade association representing about 400 member companies. The Western States Petroleum Association ("WSPA") is a regional trade association representing 39 member companies. Our members are engaged in all aspects of the petroleum industry: exploration, production, transportation, refining and marketing. Many of our members are actively engaged in activities involving crude oil produced on federal lands and together they account for the vast majority of crude oil royalties paid every year. We therefore have a substantial interest in the Minerals Management Service's ("MMS") crude oil valuation rulemaking.

API and WSPA, along with other associations and individual member companies, have participated actively at every stage of this rulemaking, filing several sets of comments[1] and participating in MMS workshops. Today's comments incorporate

[1] *See,e.g.,* API May 27, 1997 comments on the MMS' initial proposal at 62 FR 3742 (January 24, 1997); API August 1, 1997 comments on the MMS' supplementary proposal at 62 FR 16116 (April 4, 1997); API November 4, 1997 comments on the alternatives for rulemaking and related workshops at 62 FR 49460

our prior comments by reference and, to the fullest extent possible, focus on the MMS' February 6, 1998, supplementary proposed rule ("February 1998 Proposal").

Although there are marginal improvements over past proposals, the MMS' February 1998 Proposal still has core flaws. Despite MMS claims, it does not offer certainty, it does not reduce administrative costs, it does not reduce litigation, and does not arrive at the value of production at the lease. Although the appended comments describe these flaws in detail, the highlights are as follows:

- For arm's length transactions, the February 1998 Proposal's expansive definition of "affiliate" still unduly excludes many bona fide arm's length transactions from the application of gross proceeds for valuation of crude oil production for royalty purposes. ***The MMS should retain the existing regulation's definitions of "arm's length contract" and " affiliate."*** *See* Part I at 1-2.

- For non-arm's length transactions, the February 1998 Proposal employs an approach that differs appreciably among three geographic regions. For large companies operating in more than one region, this necessitates the creation of parallel and different administrative systems, needlessly magnifying compliance costs and creating artificial differences in valuation standards. ***The MMS should abandon its three-region approach and instead revise its existing regulations to include a menu of suitable benchmarks (e.g., viable tender program), flexible enough to accommodate different transactional settings while arriving at the "value of production" at the lease.*** *See* Part II at 2-3.

- For non-arm's length transactions, the details of the three-region approach pose particular problems. The use of Alaska North Slope (ANS) spot prices is unsatisfactory for the valuation of crude oil production in California and Alaska because it does not reflect the value of that production. For the Rocky Mountain Region, the use of an ordered benchmark menu (comprising an illusory tendering program, volume-weighted average gross proceeds accruing to sellers, and NYMEX futures prices at Cushing) is unwieldy at best. For all areas outside California, Alaska and the Rocky Mountain Region, the reliance on spot prices ignores the fundamental shortcomings of spot prices for valuation of crude oil. ***The MMS should abandon its three-region approach and instead revise its regulations to include a menu of suitable benchmarks (e.g., a viable tender program), flexible enough to accommodate different transactional settings while arriving at the "value of production" at the lease.*** *See* Part II at 3-4.

(September 22, 1997); and, Joint Association December 5, 1997 comments on the rulemaking issues in general.

- The February 1998 Proposal's duty to market free of charge and mandatory use of indexing in combination with imprecise location/quality differentials moves valuation well downstream of the lease and leads to values well in excess of any reasonable "value of production," the royalty standard required by applicable mineral leasing statutes, applicable oil and gas leases, and the most relevant court decisions. ***The MMS should allow reasonable deductions for post-production marketing costs and services in order to arrive at the "value of production" at the lease.*** *See* Part III at 5 and Part IV at 5-6 .

- The February 1998 Proposal's categorical elimination of FERC tariffs for transportation allowances is arbitrary and capricious. ***The MMS should leave the existing regulations unchanged and permit use of FERC tariffs.*** *See* Part V at 7-8.

- Notwithstanding the MMS' early professed goal of certainty, the February 1998 Proposal is riddled with uncertain requirements. Many of these provisions are simply vague. Many others presume an unchanging environment and do not explain how a lessee is expected to handle changes in circumstances. Many provisions would impose complex demonstration and ambiguous information collection requirements on lessees, yet the most the MMS is willing to offer is "non-binding guidance determinations." ***The MMS should undertake a fundamental revision of its proposed valuation procedures to eliminate its vague and uncertain requirements and offer meaningful valuation determinations that can be relied on by lessees.*** *See* Part VI at 8-14.

- The February 1998 Proposal's obsession with the "ultimate purchaser" leads to tracing requirements that are especially laborious and costly and, in some cases, impossible to satisfy because of antitrust prohibitions, proprietary data limitations, and the identity-masking consequences of commingling. ***The MMS should focus on the "value of production" at the lease and eliminate unnecessary downstream tracing requirements; this could involve reasonable valuation procedures or use of royalty-in-kind.*** *See* Part VII at 14-16.

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API urges the MMS to redirect this wrongheaded rulemaking to address the systemic problems set forth above. If nothing else, the February 1998 Proposal underscores the need to explore royalty-in-kind as a meaningful alternative for conventional crude oil valuation procedures. If you have questions, please call David Deal of my staff at (202) 682 - 8261.

Sincerely,

G. William Frick

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Enclosures

American Petroleum Institute and
Western States Petroleum Association
Comments on Minerals Management Service
Supplementary Proposal on
Valuation of Crude Oil Produced on Federal Leases
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Comments on Minerals Management Service
Supplementary Proposal on
Valuation of Crude Oil Produced on Federal Leases
30 CFR 206, 63 FR 6113 (February 6, 1998)

The American Petroleum Institute ("API") and the Western States Petroleum Association ("WSPA"), and industry generally, have participated actively at every stage of this rulemaking, filing several sets of comments[1] and participating in Minerals Management Service ("MMS") workshops. Today's comments incorporate our prior comments by reference and, to the fullest extent possible, focus on the MMS' February 6, 1998, supplementary proposed rule ("February 1998 Proposal").[2]

As our comments show, the February 1998 Proposal does not satisfy the MMS' own claims.[3] It would not offer simplicity or certainty. It would not reduce compliance and administrative costs. It would not reduce the need for valuation determinations or litigation. And it would not arrive at the value of production at the lease.

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[1] *See, e.g.,* API May 27, 1997, comments on the MMS' initial proposal at 62 FR 3742 (January 24, 1997), August 1, 1997, comments on the MMS' supplementary proposal at 62 FR 16116 (April 4, 1997), November 4, 1997, comments on the alternatives for rulemaking and related workshops at 62 FR 49460 (September 22, 1997), and, Joint Association December 5, 1997, comments on the core rulemaking issues.

[2] 63 FR 6113-6141(February 6, 1998), enclosed as Attachment "**A.**"

[3] In its 1998 economic analysis of the February 1998 Proposal, the MMS states:

> Specifically, the proposed rule would result in:
> - simplification of pricing, coupled with certainty,
> - reductions in valuation determinations and litigation,
> - reduction in industry group compliance costs, and
> - receipt of market value of oil produced from Federal leases.

Economic Analysis of Proposed Federal Oil Royalty Valuation Rule under Executive Order 12866," MMS, 1998, at 24.

I. The Proposal's Provisions for Valuation of Arm's Length Contracts Arbitrarily and Capriciously Exclude Many Bona Fide Arm's Length Contracts.

By its terms, §206.101 would be inapplicable to transactions involving affiliates. And §206.100 would define "affiliate" to include "a person who owns, is owned by, or is under common ownership with another person to the extent of 10 percent or more of the voting securities of any entity, interest in a partnership or joint venture, or other forms of ownership." Together, these provisions of the February 1998 Proposal arbitrarily and capriciously exclude an unduly large segment of the arm's length transaction universe from gross proceeds-type valuation under §206.102.

With minimal explanation, the February 1998 Proposal would abandon the careful compromise reached in the 1988 regulations. Based on BLM coal leasing regulations, which remain unchanged,[4] the 1988 MMS royalty valuation regulations avoid the simplistically low 10 percent threshold of the present February 1998 Proposal. Instead, the 1988 regulations reflect a sensible and fair control approach:

(i) Ownership in excess of 50 percent constitutes control;
(ii) Ownership of 10 through 50 percent creates a presumption of control; and
(iii) Ownership of less than 10 percent creates a presumption of noncontrol.[5]

To the extent the MMS' speculative, "gaming" concerns had some foundation,[6] the "misconduct" provisions of §206.102(c)(2)(i) would carry forward existing regulations[7] These regulations already provide the MMS with ample means to deal with any sham arrangement employed to understate actual control. What the MMS should do is use such existing authority to curb real misuse of gross proceeds valuation on a case-by-case basis. What the MMS should not do is use anecdotal information on an isolated situation as the pretext for adopting a narrow definition of arm's length contract to unduly narrow use of gross proceeds for valuation.

II. The Proposal's Provisions for Valuation of Non-Arm's Length Contracts Are Arbitrary and Capricious.

Our concerns over valuation of non-arm's length transactions involve the unnecessary complications of a three-region approach and the separate problem of

[4] 43 CFR 3400.0-5(rr)(3)(1998). Curiously, but commendably, the MMS' most recent proposal for valuation of crude oil on Indian lands retains the existing control approach. 63 FR 7089, 7099 (February 12,1998).

[5] 30 CFR 206.101(1997).

[6] *See* February 1998 Proposal at 63 FR 6117 (1st col.), *citing* the use of a cooperative venture addressed in Xeno, Inc. 134 IBLA 172 (1995).

[7] *See* 30 CFR 206.102(b)(1)(iii)(1997).

using indexing in its various forms. The February 1998 Proposal deals with neither satisfactorily.

A. Geographic Non-Uniformity

In comments submitted earlier in the rulemaking,[8] industry emphasized that geographically non-uniform valuation regulations impose extra burdens on companies that produce oil and gas in several geographic regions. If the valuation regulations vary appreciably from region to region, different administrative systems would be needed to support them, i.e., different software and additional staff.

In dismissing industry's non-uniformity concerns as a "one size fits all" approach,[9] the MMS misses the point altogether. In explaining the extra costs and complications of the MMS' rigid, three-region approach, industry has not promoted another even more rigid approach. From the outset of this rulemaking, industry has urged the MMS to revise the single menu approach of the existing regulations.[10] Such a revised menu, which could, for example, eliminate the posted price benchmark and include a tendering benchmark, would be flexible enough to accommodate radically different circumstances inside and outside any geographic area.

Stated most simply, in revising its valuation regulations, the MMS should focus on variations in transactional settings, not arbitrary geographical boundaries.

B. Valuation of Non-Arm's Length Transactions Generally

Geographic differences aside, earlier industry comments also explained why indexing in combination with MMS-set differentials do not arrive at a reasonable "value of production." However, the February 1998 Proposal fails to address the core concerns raised by industry.

1. §206.103(a) California and Alaska

Previously filed comments explain at length why Alaska North Slope (ANS) spot prices are a wholly unsatisfactory measure of the value of production.[11] Yet without responding to these comments, the February 1998 Proposal simply carries the MMS' January 1997 Proposal forward without any discernible change. The use of ANS spot prices offers no safeguards to protect either the operator -- or the MMS-- if the ANS

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[8] API November 1997 Comments at 5-6; Joint Association December 1997 Comments at 3.

[9] "Federal Crude Oil Valuation Rulemaking," MMS Congressional Briefings, February 1998, enclosed as Attachment "**B**," and "MMS Proposes Further Amendments to Federal Crude Oil valuation Rule," MMS News Release, February 5, 1998, enclosed as Attachment "**C**."

[10] API May 1997 Comments at 7-9; API November 1997 Comments at 4-5; Joint Association December 1997 Comments at 2-3.

[11] API May 1997 Comments at 10-14; API November 1997 Comments at 4; Joint Association December 1997 Comments at 4.

Index and the value of California crude deviate from each other because of short term market conditions (e.g., refinery supply requirements).

ANS spot prices simply do not reflect the "value of production" at the lease and we urge the MMS again to abandon this flawed approach.

2. §206.103(b) Rocky Mountain Region

The February 1998 Proposal's treatment of the Rocky Mountain Region has several flaws. First, proposed §206.101 defines "Rocky Mountain Region," but excludes New Mexico. As the preamble to the February 1998 Proposal suggests, [12] at least the northwest portion of New Mexico should be included in the Rocky Mountain Region.

Second, proposed §206.103(b)(1) permits use of an MMS-designed tendering program whose myriad limitations all but eliminate the tendering program as a meaningful option, even for the Rocky Mountain Region. These undue limitations in §206.103(b)(1) include the requirement that 33 1/3 percent of production be offered and sold, the requirement that at least three bids be received, the requirement that bidders not have a tendering program of their own, and the prospect of other criteria to be published in the MMS' "Oil and Gas Payor Handbook."

Third, even though the MMS has abandoned NYMEX index prices in general, proposed §206.103(b)(3) would still use them for the Rocky Mountain Region. Given the demonstrably flawed character of NYMEX index prices as a measure of the value of production,[13] NYMEX index prices should be abandoned altogether, even in the Rocky Mountain Region.

Fourth, and most fundamental, the MMS offers no rationale for limiting use of a tendering program to the Rocky Mountain Region. Although the MMS' Fall 1997 workshops demonstrated a broad base of support for the use of a properly designed tendering program as an alternative to indexing generally, the February 1998 Proposal is an unfounded de facto rejection of the concept. API urges the MMS to reassess its rejection of tendering as a generally applicable method for valuation and eliminate the crippling operational and geographic limitations for its use.

3. §206.103(c) Other Areas

The February 1998 Proposal's treatment of the bulk of the nation and the vast bulk of its production remains riddled with fundamental problems. Although the February 1998 Proposal would use spot prices instead of the January 1997 Proposal's use of NYMEX prices, the February 1998 Proposal offers no response to the focused criticism of crude oil spot prices as a measure of value for royalty purposes. As earlier

[12] February 1998 Proposal at 63 FR 6116 (third col.).

[13] API May 1997 Comments at 15-23; API November 1997 Comments at 2-3.

API comments have painstakingly explained,[14] spot prices for crude oil (unlike spot prices for gas) are an altogether inappropriate measure of the value of production and the MMS should abandon their use for valuation purposes. API urges the MMS to avoid the use of crude oil spot prices that are a demonstrably inaccurate measure of the "value of production" at the lease.

As noted above, the MMS should instead revise the existing benchmark regulations to provide an menu of suitable valuation measures from which lessees could select the one best suited to fit the particular transactional circumstances.

III. The Proposal Unlawfully Requires That Production Be Marketed at No Cost to the Lessor.

Although the MMS continues to claim that "royalty must be based on the value of production,"[15] that position is hard to square with the February 1998 Proposal's treatment of marketing costs. Like the original January 1997 Proposal, proposed §206.106 states:

> You must place oil in marketable condition <u>and market the oil</u> for the mutual benefit of the lessee and the lessor <u>at no cost</u> to the federal government unless otherwise provided in the lease agreement . . . . If you use gross proceeds under an arm's length contract in determining value, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides services that the seller normally would be responsible to perform to place the oil in marketable condition <u>or to market the oil</u>. (Emphasis supplied.)

As earlier comments make clear,[16] an express duty to market free of charge is not a clarification of existing law, but is a substantial change. To "place the oil in marketable condition," the requirement of existing regulations,[17] does not encompass "marketing the oil." This change contravenes the "value of production" language of applicable mineral leasing statutes, and the most relevant court decisions interpreting that language.[18] Furthermore, there is no implied covenant to market free of charge.

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[14] API November 1997 Comments at 2-3.

[15] MMS Congressional Briefings, February 1998; MMS News Release, February 5, 1998.

[16] API May 1997 Comments at 34-39; API November 1997 Comments at 3-4; Joint Association December 1997 Comments at 3.

[17] 30 CFR 30 CFR 206.102(f)(1997).

[18] *See, e.g.*, Diamond Shamrock Exploration Company v. Hodel, 853 F.2d 1159(5th Cir. 1988).

Regrettably, the MMS seems intractable on this issue and industry legal challenges have already been filed in connection with the related gas transportation allowance rulemaking to obtain a judicial interpretation of this core issue.[19]

IV. The Proposal Unlawfully Moves the Point of Valuation Downstream of the Lease Without Allowing Deductions for All Post-Production Marketing Costs and Services.

Independent of the Proposal's attempt to unlawfully impose on the lessee a duty to market free of charge, the Proposal contains several other provisions, which, like the use of spot prices, effectively move the valuation point downstream, away from the lease and point of production. Starting downstream inherently complicates the valuation process, because other parties and other records are involved and because the identity of the production is obscured through commingling. However, it can approach the "value of production," provided ample allowances are permitted for post-production costs and services, beyond the costs of placing the production in marketable condition.

Yet the February 1998 Proposal does not account for such added value. As noted above in Part 3, §206.106 categorically denies deductions for marketing costs. Moreover, as earlier comments explain, once production moves downstream, it acquires various increments of value linked with the process of marketing beyond the simple physical treatment to put it in marketable condition.[20]

What aggravates the problem is February 1998 Proposal's stifling treatment of arm's length transactions and the inordinate requirement for downstream tracing of proceeds. For example, even where §206.102 would be applicable, it would in many cases be available only after one or more resales have occurred. As explained in Part I of these comments, the §206.101 definition of "affiliate" would deny the use of gross proceeds under §206.102 for many bona fide of arm's length transactions. As a result, §206.101(a)(3) would permit the use of gross proceeds only after the crude oil is "ultimately sold" under an arm's length contract.[21]

Likewise, where no arm's length contract (by the MMS definition) exists, even downstream, §206.103 would require, except for some limited cases in the Rocky Mountain Region, the use of spot prices or NYMEX index prices (together with location/quality differentials) that are by definition prices far downstream. Here again, prior API comments explain why the use of spot prices or NYMEX index prices used in

[19] *See, e.g.*, Independent Petroleum Association of America v. Armstrong et al., 98 CV 531 (filed March 2, 1998) and American Petroleum Institute v. Babbitt et al., 98 CV 631 (filed March 13, 1998).

[20] API May 1997 Comments at 24-25.

[21] MMS February 1998 Proposal at 63 FR 6116(third col.). *See also*, proposed §206.103(b)(3) that, for certain transactions in the Rocky Mountain Region, would permit a lessee to use the gross proceeds from sales or resales of crude.

combination with clumsy differentials almost invariably lead to values higher than a reasonable "value of production," values which capture increments of value added as the crude oil moves downstream.[22]

If the MMS were to abandon its contracted view of arm's length transactions and its correlative reliance on index-type prices, the MMS could avert this downstream valuation problem.

V. The Proposal Unlawfully Limits Transportation Allowances

Without any further commentary or response to industry comments, the February 1998 Proposal carries forward the treatment of FERC tariffs in the January 1997 Proposal. Under the existing regulations, a lessee can use the actual costs of transportation or apply for use of FERC or state-approved pipeline tariffs.[23] Under the February 1998 Proposal, §206.105 would eliminate the use of tariffs altogether using the rationale that "a FERC-approved tariff is no longer a viable alternative since FERC ruled that it lacks jurisdiction to enforce the Interstate Commerce Act. See Oxy Pipeline, Inc., 61 FERC 61,051 (1992) and Bonito Pipe Line Company, 61 FERC 61,050 (1992)."[24]

API's May 1997 Comments point out that the Oxy and Bonito cases by their own terms are limited to offshore pipelines.[25] More importantly, API's May 1997 Comments also show that the MMS itself has rejected the sweeping significance now claimed.[26] Yet nowhere does the February 1998 Proposal respond to these earlier comments. Moreover, the February 1998 Proposal is arbitrary and capricious for several other reasons:

First, the MMS offers no explanation of how the February 1998 Proposal satisfies OCS Lands Act §§5(e) and (f).[27] These sections oblige the Secretary to prohibit unlawful discrimination in oil and gas transportation arrangements on the OCS. Yet the transportation allowance provided by the February 1998 Proposal requires the lessee to move the Federal Government's produced oil at a rate presumptively lower than that provided for movement of third party production, even if it is moved through the same pipeline on the same day. In effect, the MMS would penalize the lessee whose affiliate

[22] API May 1997 Comments at 15-23; API November 1997 Comment at 2.

[23] 30 CFR §206.103(b)(5) (1997).

[24] 62 FR 3742, 3747 (January 24, 1997).

[25] API May 1997 Comments at 29-31.

[26] Id., *citing* Torch Operating Co., MMS-94-0655-OCS at 5 (January 18, 1997). The Assistant Secretary's more recent February 4, 1998, decision rejecting use of FERC tariffs also cites the FERC decision in Ultramar, Inc. V. Gaviota Terminal Co., 80 FERC 61,201 (1997), but does not alter this situation.

[27] 43 USC § 1334(e) and (f).

undertakes the installation of pipeline infrastructure in deep water. The MMS would deny a full transportation allowance to the party who undertook the cost, risk, and research and development expense, while granting to other parties using the line at arm's length a full transportation allowance. Such a result is discriminatory and unfair.

Second, the MMS offers no justification for its failure to satisfy the OCS Lands Act § 5(a) requirement that the Secretary cooperate with other federal agencies.[28] As the agency charged by statute to set pipeline rates, FERC deserves to have its ratemaking procedures recognized by the MMS absent a clear and compelling reason in the administrative record. The MMS offers none because there is none.

Third, the February 1998 Proposal's limitation of transportation allowances is inconsistent with the basic principle that royalty be based on the "value of production," because the value of production should not include any increment of the cost of transportation.

Fourth, the proposed methodology for transportation allowances, when viewed in combination with the proposed methodology for arriving at the value of production, underscores the arbitrary and capricious nature of the February 1998 Proposal. In Part I of these comments, we showed how the MMS takes great pains to limit the definition of "arm's length contract" through recourse to an expansive definition of "affiliate."[29] This has the practical effect of requiring an unduly high number of transactions to be considered non-arm's length transactions; because this leads to use of spot prices in combination with imprecise location/quality differentials, the result is an unlawful increase in the imputed value of production. Yet for transportation costs, the February 1998 Proposal chooses to ignore what third parties, unaffiliated by anyone's definition, pay to move production through the same pipeline. These unaffiliated third party costs are plainly comparable and discernible, given the availability of published FERC rates, and are plainly the best measure of transportation costs. Yet ignoring them results in an unlawful decrease in transportation allowances, further increasing a lessee's net royalty obligation.

Fifth, the February 1998 Proposal's treatment of transportation allowances falls especially harshly on offshore production where the costs of construction and installation of transportation infrastructure especially high and risky. As a de facto increase in royalty rates, an unduly limited transportation allowance policy is at odds with the public policy recognizing the need for royalty relief as an incentive for offshore development [30] and the Secretary's overarching statutory obligation to make the OCS available for "expeditious and orderly development."[31]

[28] 43 USC § 1334(a).

[29] *See* Part I, *supra* at 1-2.

[30] Outer Continental Shelf Deep Water Royalty Relief Act, P.L. 104-58, 109 Stat. 563, codified at 43 USC § 1337(a), OCS Lands Act § 8(a).

[31] 43 USC §1332(2).

For all of these legal and policy reasons, the MMS should abandon the February 1998 Proposal's categorical rejection of FERC tariffs.

VI. The Proposal Establishes a Valuation Scheme Riddled with Uncertainty.

At the outset of this rulemaking, the MMS professed the need for valuation certainty, yet that element is conspicuously lacking from the February 1998 Proposal and related MMS briefing materials.[32] Indeed, key elements of the February 1998 Proposal fail to give payors meaningful guidance. Indeed, if anything, the heavy requirement for tracing of proceeds downstream increases complexity and uncertainty.

In many places, key provisions are simply vague. In other places, critical decision criteria are unspecified altogether. In still other places, key provisions leave unaddressed how changes in circumstances impact royalty obligations.

§206.100

- If under § 206.100(b) the "express provision of an oil and gas lease" would override any regulation, as it must, what happens when the gross proceeds provision of a lease arrives at a different value than indexing?

- Under § 206.100(b), the regulations would not apply where "inconsistent with a federal statute, a settlement agreement between the United States and a lessee resulting from administrative or judicial litigation, or an express provision of an oil and gas lease. . . . " This litany of overriding provisions should also include existing and future royalty reduction agreements entered into by the MMS and operators. These agreements have a clear statutory basis and are critical for the development of certain oil reserves.

§206.101

- *"Aggregation point"*: How often would MMS publish its list? How do changes in the list affect payors that have relied on prior lists? How would the regulation deal with OCS aggregation points, many of which are located on the seafloor at a location not generally in use by producers? Since the distance of such aggregation points is not delineated, how would that distance be calculated? Since in some instances producers have already paid to move the production from the lease to the shore, how would that rate be pro rated for royalty purposes?

- *"Area"*: Defining this term as a "geographic region at least as large as the limits of an oil field in which the oil has similar quality, economic, and legal characteristics" suggests the possibility of an unduly expansive definition as applied. In recent

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[32]The February 1998 Proposal and the MMS Congressional Briefings, February 1998, do not include certainty as an objective. Yet at earlier stages in the rulemaking, certainty was a primary objective. *See, e.g.*, January 1997 Proposal at 62 FR 3742; September 1997 Notice at 62 FR 49460, 49461 .

California-related orders, the MMS has taken the position that the entire state is the field or area; such an expansive definition severely limits the viability of tendering programs included in §206.103(b).

- *Arm's-length contract*": Inasmuch as the proposed definition of arm's length contract depends so much on an expansive definition of "affiliate" and looks beyond the time of execution of the original agreement, the proposed definition does not clearly and fairly deal with the changes in circumstances that can occur between parties after they have executed an arm's length contract? For example, where two parties enter into an agreement that satisfies the MMS' own definition of arm's length contract, then later become more closely related, why should that agreement later be considered a non-arm's length contract if the substantive terms of the original agreement are unchanged?

- "*Index pricing point*": If the list of MMS-approved publications changes, how would this affect payors that have at one point relied on the current list of approved publications?

- *"Gathering".* The distinction between gathering and transportation should be clarified and revised to reflect modern technology. This is especially true for deep water OCS leases where the traditional distinctions between gathering and transportation do not apply. Subsea development requires movement of production for distances of 20-800 miles and for such distances to deny a transportation allowance altogether would be arbitrary and capricious. In addition, deep water above surface structures (e.g., TLP, SPAR) require an associated shelf jump off location; in such cases, movement of production from the lease to the shelf should be classified as transportation.

- *"Gross proceeds"*: What elements are included in "marketing"? Why has the phrase "accuring to an oil and gas leasee" be deleted? Its deletion blurs the fundamental principle that the lessee has the royalty obligation. This key phrase should be restored to the definition.

- "*Index pricing*": What constitutes "other" appropriate crude oil spot prices for royalty valuation?

- "*Market center*": How would changes in market centers affect payors?

- *"Spot price*": What does "a specified period of short duration" mean?

- "*Tendering program*": What does the phrase "other geographical/physical unit" mean?

§206.102

- How and when would MMS determine that an agreement reflects "reasonable location and quality differentials" under §206.103(c)(3)? no criteria have been prescribed.

- How and when would a lessee demonstrate that an agreement is arm's length under §206.102(d)(1)?

- Would payor "certification" under (d)(2) be subject to later review by the MMS? Before an audit? If the MMS is only willing to offer a "non-binding determination" under §206.107, how can the MMS require a certification from the payor, then review it?

§206.103

- What criteria would be used by the MMS for review of a tendering program under §206.103(b)(1) to implement the 33 1/3, three bidders, and 50% requirements? What time period does the MMS have in mind? Can a payor slip in and out of eligibility? When will additional criteria appear in the MMS "Oil and Gas Payor Handbook"? When would the MMS approve a tendering program? How would a payor know with certainty whether a potential bidder has what the MMS considers an acceptable tendering program?

- What does "the MMS Director may establish an alternative valuation method" mean? Is this a case-by-case option or does it suggest that the MMS may at some unspecified point in the future establish another generally applicable valuation method? If the former, would the decision be binding on the MMS or is that also subject to later reconsideration by the MMS? If the latter, is it appropriate to experiment with a radical change in valuation methodology given the high costs of system conversion?

- How and when does the MMS determine under (d) if index prices are "unavailable or no longer represent reasonable royalty value"? What are "other relevant matters"?

- Under §206.103(e), would the payor and the MMS be locked into an alternative for some prescribed time period?

§206.104

- How often would the MMS review or revise its approved publication list?

§206.107

- How does the availability of "non-binding determinations of guidance" under §107 promote certainty? The MMS should offer determinations comparable to Internal Revenue Service (IRS) private letter rulings[33] for specific taxpayers based on

[33] IRS Rev. Proc. 80-20, 1980-1 C.B. 633, *as modified by* Rev. Proc. 81-33, 1981-2 C.B. 564.

specific facts. Such IRS rulings can be revoked, but they are not "non-binding" ab initio.

- Would there be guidelines for gauging whether the MMS "promptly" reviews a lessee-proposed valuation method?

- Would interest and penalties apply where the payor relies on an MMS "non-binding determination" to its detriment? Would the MMS then be free to disavow its own determination of value by seeking to use the civil and criminal penalties of FOGRMA and other statutes to cow lessees? Since such an MMS determination would be "non-binding," could a lessee disregard it with impunity?

§206.109

- How would subsea transportation be handled? *See* comments under §206.101 above.

§206.110

- Under §206.110(a), how would a payor demonstrate that a transportation-related contract is arm's length?

- How and when does the MMS determine under §206.110(a)(1) that the "contract reflects more than the consideration actually transferred either directly or indirectly" to the transporter for transportation?

- Under §206.110(b)(2), would alternative allocation methods, once approved, be binding?

§206.112

- Under §206.112(b)(2), if the use of Form 4415-generated location/quality differentials is subject to audit, how promptly would revisions be made?

- Under §206.112(b)(2), what criteria would the MMS use to exclude apparent anomalous differentials from the calculation of differentials applicable to each aggregation point?

- How would the proposed regulations deal with the impact of blending crude oils of different grades? Such blending occurs away from the lease and the MMS as lessor has no claim on the value added-- or lost-- away from the lease.

- Under § 206.112(b)(3), would the MMS revise the location/quality differential retroactively? Any such changes should be prospective only.

- What would happen if the transportation costs in a succeeding year far exceed the transportation costs of the preceding year that had been used to calculate the differentials? How would a payor ever catch up in an escalating transportation cost scenario? What would happen when volumes differ because of production shut-in caused by development or expansion?

- Under §206.112(d), would lessees bear the entire administrative/interest/penalty burden if the MMS revises the location/quality differentials?

- Under §206.112(e), how would quality differences be accounted for where no formal quality bank exists? Quality banks are not employed in every case, but are the result of market forces mediated by the respective bargaining positions of shippers and transporters.

§206.113

- What does the term "directly" mean in connection with moving lease production under §206.113(b) & (c)?

- Under §206.113(b), if crude oil passes through a market center en route to a refinery, would the transportation allowance be limited only to the lease-to-market center segment?

§206.114

- What criteria would the MMS employ in the approval process for an alternative location/quality differential? When would these criteria be available to a payor? Would MMS approval be binding?

- Does the MMS contemplate prescribing a period for ruling on a lessee-proposed differential (e.g., 60 days)? Why not establish a presumption in favor of granting such a request in order to keep the process moving without undue delay?

§206.115

- Does the MMS intend to preserve the ability to retroactively modify its list of aggregation points and market centers? Should not such revisions be prospective only?

§206.116 & §206.117

- Given the use of the term "may," under what circumstances would a payor have to submit "transportation contracts, production agreements, and related documents" (under §206.116) or "all data" (under §206.117)? What would the MMS do with this huge amount of information?

- How would an affiliate file a Form MMS-2014? Under what statutory authority does such an obligation rest?

- What would the consequences for a payor be if its affiliate files incorrect information on Form MMS-2014?

§206.118

- Are the first two sentences consistent? The first sentence requires information "related to all your and your affiliate's production," yet the second sentence requires only information on "differentials between MMS-defined market centers and aggregation points."

§206.122

- Why has the MMS eliminated references to the point of settlement approved by the MMS for offshore leases?

- Why is there no adjustment provided for offshore leases where the quality/quantity is different from quality/quantity at the point of settlement?

Form MMS-4415

- If MMS-4415 is limited to federal production, and federal production is commingled with non-federal production, what should be reported?

- What if the sulfur differential is not referenced in the contract?

- Would a certification be required of a party who signs Form MMS-4415? The step-by-step instructions for the form use the heading "certification" but the form itself does not.

- If the MMS has reserved the right to review any information on Form MMS-4415 relating to non-federal production, how long would a payor have to retain this information? Until an audit? Under what statutory authority does the MMS regulate a non-lessee?

Left uncorrected, these deficiencies are more than a burden; they pose for lessees an unreasonable dilemma. In the absence of clarification--or even with "non-binding determinations of guidance" from the MMS -- is a lessee expected to overpay as a hedge against an interpretation later deemed wrong? Even if a lessee makes his own good faith interpretation, and procures MMS "non-binding guidance," and overpays, how does that protect against bogus, after the fact, assertions of non-compliance with federal laws? Stated most simply, under the February 1998 Proposal, payors simply cannot conduct their business with reasonable assurance that they are satisfying their royalty obligation.

VII. Many Requirements of the Proposal Are Unduly Costly or Unworkable.

A. <u>Costs</u>

Even if the vagaries listed above under Part VI of these comments were eliminated, the February 1998 Proposal contemplates changes that would impose very significant implementation costs. Although the costs would vary from company to company, and cannot be estimated because of the February 1998 Proposal's vagueness on several core issues, the changes are pervasive.

Even as revised, Form MMS-4415 would require the collection of substantially more information. New or modified computer systems would be necessary to capture sales and exchange data, calculate prices, perform recalculations when any component of the price changes, especially if downstream tracking is required. For a company producing in more than one region, the February 1998 Proposal's three-region approach further compounds the problem. All of these requirements require new systems and more personnel to address the additional complexity.

To a large degree, the changes that would be required by the February 1998 Proposal are driven by the collection of voluminous information to be submitted on existing Form MMS-2014 and proposed Form MMS-4415. However, two reports submitted recently to the Office of Management and Budget reveal many profound problems with that proposed data collection effort.

For example, the Barents Form 2014 Report[34] shows that the MMS, in attempting to satisfy its Paperwork Reduction Act obligations, has grossly underestimated the increased burden for completion of Form MMS-2014. This underestimate is attributable to significant computation errors[35] and gross underestimates of the new information collection requirements implied by the February 1998 Proposal.[36]

Likewise, the Barents Form 4415 Report[37] shows that the MMS has ignored the impact of the February 1998 Proposal on existing forms,[38] underestimated the effort to complete form MMS-4415,[39] and underestimated the costs of payor system changeover and implementation.[40] The 4415 Report also shows that the form completion requirements are open to misinterpretation[41] and that the MMS' intended use of the

[34] "Analysis of the Department of Interior, Minerals Management Service's Request for Extension of the Existing collection Authority for Form MMS-2014," Barents Group, March 6, 1998, ("Barents Form 2014 Report"), enclosed as Attachment **"D."**

[35] Id. at 2-3.

[36] Id. at 8-11.

[37] "Analysis of the Department of Interior, Minerals Management Service's Form MMS-4415 under the Supplementary Proposed Rule Establishing Oil Value for Royalty Due on Federal Leases under the Paperwork Reduction Act," Barents Group, March 10, 1998 ("Barents Form 4415 Report"), enclosed as Attachment **"E."**

[38] Id. at 11-12.

[39] Id. at 12-13.

[40] Id. at 14.

[41] Id. at 16-17.

information is not clear.[42] Finally, the 4415 Report shows that the contemplated method for calculation of location and quality differentials ignores the commingling of federal and non-federal lease oil,[43] presents statistical validity problems[44] and will not lead to accurate valuation estimates.[45]

In sum, the February 1998 Proposal contemplates information collection and system changes far more burdensome than the MMS has estimated. If, indeed, the February 1998 Proposal is intended to satisfy the MMS' objective to " reduce administrative costs of royalty valuation,"[46] it fails. It certainly fails on the industry side and we believe on the MMS side as well. Moreover, if the use of some form of indexing is to result in "rules that reflect market value," that objective too fails. The valuation procedures contemplated will not arrive at the valuation outcomes predicted by the MMS: the "value of production" at the lease.

B. Workability

The valuation procedures contemplated by the February 1998 Proposal are not simple nor are they even simpler than the existing procedures. Our best assessment of the February 1998 Proposal's regulatory scheme is that it is not only unnecessarily complex and burdensome, but that it simply cannot work. Notwithstanding the MMS' occasional claims of certainty, Attachment "F"[47] shows graphically how the valuation procedures contemplated by the February 1998 Proposal are hopelessly complicated and riddled with the myriad uncertainties set forth in detail in Part VI above.

To a large degree, these complications are linked to the Proposal's pervasive and extraordinary tracing requirements. For example, even for the small fraction of bona fide arm's length transactions that could use the gross proceeds methodology of §206.102, tracing would be required where multiple exchanges occur before the "ultimate purchase" occurs. Indeed, under the February 1998 Proposal, a lessee seeking to use §206.102 would have to obtain and retain records for every downstream exchange, even though only a fraction might ultimately result in an arm's length sale. For the larger universe of transactions, where one of the three proposed sets of region-specific indexing methodologies would be used, tracing would still be required to arrive at transportation allowances.

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[42] Id. at 17-18.

[43] Id. at 14.

[44] Id. at 14-15.

[45] Id. at 15-16.

[46] *See* "Federal Crude Oil Valuation Rulemaking," MMS Congressional Briefings, February 1998.

[47] "How Will Royalty Value Be Calculated under MMS Proposed Rule," enclosed as Attachment "F."

Yet nowhere does the Proposal address the core problems of downstream tracing: Antitrust laws prohibit the exchange of certain market information. Proprietary concerns, sometimes reinforced by other statutory requirements, inhibit the exchange of information among parties.[48] Commingling of streams, essential for pipeline efficiency and operation, eliminates the identity of production because multiple streams of federal and non-federal production are often aggregated and disaggregated as the crude oil moves downstream. And even without commingling, lessees cannot reasonably be expected to have or acquire records for every downstream transaction when so many so many parties outside the control of the lessee may be involved.

In sum, the February 1998 Proposal presumes a level of access to basic downstream information that simply does not exist because of antitrust, competitive and operating reasons beyond the control of a lessee. What the MMS should do is revise its existing regulations to provide workable and reasonable valuation procedures and make full use of royalty-in-kind to avoid this unnecessary problem.

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[48] For example, §§3 and 41(l) of the Interstate Commerce Act prohibit a covered common carrier pipeline from discriminating in favor of one shipper over its other shippers; indeed, §41(l) makes such discriminatory conduct a criminal offense. A common carrier generally has no reason to provide detailed information concerning its actual costs for any pipeline movement to all of its shippers and it cannot provide that information to any one shipper.